TECHNICAL REVIEW DOCUMENT for OPERATING PERMIT 950PEP107

to be issued to:

Colorado Springs Utilities

Martin Drake Power Plant
El Paso County
Source ID 0410004

Michael E. Jensen October 15, 2002

I. PURPOSE

This document establishes the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA and during Public Comment. This narrative is intended only as an adjunct for the reviewer and has no legal standing. Conclusions in this document are based on information provided in the original application submittal of December 20, 1995, and supplemental Title V technical information submittals for February 26 and September 9, 1996; a site visit on March 20, 1997; an information submittal of August 25, 1998; technical information submittal for June 21, 1999, previous inspection reports, as well as numerous telephone contacts with the applicant.

On April 16, 1998, the Colorado Air Quality Control Commission directed the Division to implement new procedures regarding the use of short term emission and production/throughput limits on Construction Permits. These procedures are being directly implemented in all Operating Permits that had not started their Public Comment period as of April 16, 1998. All short term emission and production/throughput limits that appeared in the Construction Permits associated with this facility that are not required by a specific State or Federal standard or by the above referenced Division procedures have been deleted and all annual emission and production/throughput limits converted to a rolling twelve (12) month total. Note that, if applicable, appropriate modeling to demonstrate compliance with the National Ambient Air Quality Standards was conducted as part of the Construction Permit processing procedures. If required by this permit, portable monitoring results and/or EPA reference test method results will be multiplied by 8760 hours for comparison to annual emission limits unless there is a specific condition in the permit restricting the hours of operation.

The table below documents existing short term Construction Permit limits that were not incorporated in the Operating Permit.

Construction Permit	Emission Point	NOx, lb/hr	CO, lb/hr	VOC, lb/hr	PM, lb/hr	PM ₁₀ , lb/hr	Fuel Use or Process rate
84EP312	Coal Processed						5,440 tph 10,500 tpd
	Coal Handling				38.70		
94EP590	Flyash Production						51 tph
	Flyash Handling				4.1	2.1	

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this Operating Permit application have been reviewed in accordance with the requirements of Colorado Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised Construction Permit.

II. SOURCE DESCRIPTION

This facility is located in Colorado Springs, El Paso County, Colorado. There are no affected states within 50 miles of the facility. There are no Federal Class I areas within 100 kilometers of the facility. Florissant Fossil Beds is a Federal Class II land area within 100 kilometers of the facility. Florissant Fossil Beds has been designated by the State to have the same sulfur dioxide increment as Federal Class I areas. The sources addressed in this permit are considered as baseline units for increment considerations.

The Martin Drake Power Plant consists of three steam driven electric generating units, Units 5, 6, and 7. The three units are subject to the provisions of Title IV, the Acid Rain Program, of the Clean Air Act.

Name	Date	Generation Capacity	Comment		
Unit 1	July 6, 1994	NA	Retired		
Unit 2	May 31, 1991	NA	Retired		
Unit 3	1950's	NA	Boiler destroyed in explosion; turbine remained in service		
Unit 4	March 1, 1997	NA	Retired		
Unit 5	1962	51 gross mega-watts	Placed in Service		
Unit 6	1968	85 gross mega-watts	Placed in Service		
Unit 7	1974	142 gross mega-watts	Placed in Service		

The Compliance Assurance Monitoring (CAM) rule applies to each point source emission unit that: (1) is subject to an emission limitation or standard; and (2) uses a control device to achieve compliance; and (3) has precontrol emissions that exceed or are equivalent to the major source threshold (100 tons per year for any regulated criteria pollutant). If the Title V Operating Permit application has been deemed complete prior to April 20, 1998, or if the Title V Operating Permit has been issued, the CAM provisions are to be incorporated into the Title V Operating Permit at the time of the permit renewal. In accordance with the requirements of this paragraph, the following sources are subject to the CAM provisions at the time this Title V Operating Permit is renewed: the Riley Boiler (S005) fabric filter, Babcock & Wilcox boiler (S006) fabric filter, and the Babcock & Wilcox boiler (S007) boiler fabric filter.

If the Title V Operating Permit has not been issued and the application was deemed complete by April 20, 1998, an emission unit is subject to the CAM provisions if change(s) requested for the Title V application would be judged a significant modification of the Title V Operating Permit if it had been issued, and the emission unit potential-to-emit after any controls, exceeds 100 tons per year. Changes made to the ash and coal handling system construction permits and the conversion of the boiler burners to low nitrogen oxides emissions burners while the Title V Operating Permit was being prepared did not satisfy the criteria for requiring a CAM plan be included in the Title V Operating Permit being prepared.

The Colorado Springs 3-C Urbanized Area is classified as attainment for all criteria pollutants. This plant satisfies the criteria of the Prevention of Significant Deterioration/ New Source Review (PSD/NSR) industrial category for fossil-fuel fired steam plants of more than 250 million Btu per hour heat input. Under the PSD/NSR provisions, a source in one of the industrial categories achieves major stationary source status when the Potential-To-Emit (PTE) for the emissions of any regulated pollutant exceeds 100 tons per year. Therefore, this facility is classified as a major stationary source for Particulate Matter, Particulate Matter smaller than ten (10) microns, sulfur dioxide, nitrogen oxides and carbon monoxide. PSD requirements may apply, as appropriate, to any modification of any of the sources addressed in this operating permit. Any source modification, or contemporaneous modification of several sources, that results in a significant net emissions increase may require a full PSD review of the source(s) modification.

Units 5, 6 and 7 all fire low sulfur sub-bituminous coal from Wyoming or northwestern Colorado as the primary fuel. Natural gas can also be fired in these units. All three (3) units are equipped with fabric filters (baghouses) for particulate emissions control.

Construction Permit C-11,335 was prepared for the addition of a baghouse to Unit 6. Calculation sheets dated March 22, 1977, end with a note that no permit is needed. A March 29, 1977 letter to Colorado Springs Utilities (CSU) explains that the construction of a baghouse did not require a construction permit under the existing regulations. This permit was never issued and is judged to have no standing. On that basis, Unit 6 has grandfather status for the regulatory requirements for a Construction Permit.

Construction Permit C-10,381, dated March 1, 1974, was issued for modifications to the Unit 5 electrostatic precipitator. The permit had the standard six (6) month expiration date. Permit-To-Operate P-10,402 was issued December 13, 1973, for Unit 7. The only requirement listed on the permit was for the provision of an electrostatic precipitator. The permit carried an expiration date of December 1, 1975. In November, 1975 the Air Quality Control Commission repealed and readopted

Colorado Regulation No. 3. Changes made to Colorado Regulation No. 3 included the modification of the two permit system from "Authority-to-Construct" and "Permit-To-Operate" permits to "Initial Approval Construction Permit" and "Final Approval Construction Permit". Holders of existing permits were not required to comply with the revisions. The regulatory change eliminated the expiration date for both the Authority-to-Construct and Permit-to-Operate Permits. In addition, the changes exempted air pollution control equipment as a source requiring a construction permit. As a result of a July 1980, revision of Colorado Regulation No. 3, C.R.S. §25-7-114(k) stated that all existing permits at the time of the 1975 regulation change remained in full force and effect. On this basis, Construction Permits C-10,381 and P-10,402 remain in full force and effect. Construction Permit C-10,402 was apparently overlooked when a baghouse was installed to replace the electrostatic precipitator in 1993. While air pollution control equipment does not require a permit, Permit C-10,402 should have been canceled or changed to reflect the changed equipment. There would be no benefit at this time to a modification of P-10,402 just to show a baghouse has replaced the precipitator. These two permits will be noted in the Title V permit, however, they provide no enforceable applicable requirements to be included in the Title V permit.

The bottom ash from the boilers is handled by a wet system that discharges to settling ponds. The settled material is periodically removed from the ponds and transported to the Hanna Ranch Solid Waste Disposal Facility. The material is kept in a wet condition during the removal and off-site transport.

Each boiler is equipped with a cooling tower. Some of the water is lost from the cooling towers as droplets. These droplets evaporate and leave the minerals in the air as particulate matter. The amount of particulate matter released is a function of the initial mineral content in the water and the concentration of the minerals as the water is evaporated in the cooling process. The cooling tower water is treated with chlorine to limit or prevent aquatic growths in the water. Some of the chlorine is converted to chloroform in the water and subsequently lost to the atmosphere as volatile organic compound emissions from the cooling towers.

In addition to the three (3) main boilers, the Martin Drake Power Plant includes coal handling systems, flyash handling systems, and numerous insignificant activities.

The Potential-to-Emit (PTE) in the following tabulation of emissions is based on the Title V application. The emissions factors used in the application calculations were taken from AP-42 (1/95). The actual emissions are from the Division AIRS database for data year 1997 or from the Title V application if the information was not recorded in the AIRS database.

	Potential To Emit, Tons Per Year							1999		
	B005 Coal	B006 Coal	B007 Coal	P201 Coal	P202 Flyash	P206 CT #5	P208 CT #6	F211 CT #7	Total PTE	ACTUAL EMISSIONS TPY
PM	240	377	585	17	7	2	2	268	1496	213
PM_{10}	240	377	585	8	4	1	1	134	1349	185
SO_2	2880	4527	7022						14429	6596
NO_X	2604	4094	6349						13,047	5590
VOC	7	11	18			0.21	0.31	0.34	37	24
CO	91	151	233						557	213
H ₂ SO ₄ Mist	31	49	75						155	30
Pb	1	2	3						6	negligible
HAPS										110

CT = Cooling Tower

The compliance status of each source at the facility is based on the information provided in the application and a review of the office files. The Division accepts the facility was in compliance at the time the Title V application was submitted.

III. EMISSION SOURCES

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site:

Coal Firing of Boilers

Unit 5 – 548 MMBtu/Hr Riley Boiler

Unit 6 – 861 MMBtu/Hr Babcock & Wilcox Boiler

Unit 7 – 1336 MMBtu/Hr Babcock & Wilcox Boiler

1. Applicable Requirements - The descriptive information above shows the steam generator design capacity when firing coal. Fossil fuel fired steam generators which "commenced construction" prior to August 17, 1971 are not subject to NSPS Subpart D. Unit 5 was placed in service in 1962; Unit 6 in 1968; and Unit 7 in 1974. The Colorado Springs Utilities (CSU) requested the permit shield protection from NSPS Subpart D for all the units. The in-service data for Unit 7 required evidence to verify the NSPS did not apply. CSU provided information which indicates Unit 7 "commenced construction" prior to the August 17, 1971 effective date of NSPS Subpart D.

The emissions from the units were found to be subject to a number of similar applicable requirements. The following attempts to focus on the various applicable requirements related to a topic. Note that the Acid Rain sulfur dioxide and nitrogen oxides limitations only appear in Section V (Acid Rain Requirements) of the Operating Permit.

Continuous Emission Monitors

There are multiple applicable requirements for Continuous Emission Monitoring (CEM)/Continuous Opacity Monitoring (COM) systems. Colorado Regulation No. 1, Section IV requires a COM when burning coal and either a CEM for sulfur dioxide or fuel sampling to identify the coal sulfur content. If a CEM is used for monitoring sulfur dioxide, then a CEM is also required for either carbon dioxide or oxygen. Colorado Regulation No. 1, Section IV identifies other requirements for CEMs such as performance specifications (Section IV.E), calibration (Section IV.F), and notification and record keeping (Section IV.G).

These units are subject to the Acid Rain Requirements and as such are required to continuously measure and record emissions of SO₂, NO_X (and either CO₂ or O₂ as a diluent gas), and CO₂, volumetric flow, and opacity. The Acid Rain CEM requirements are specified in 40 CFR Part 75. For this Operating Permit the data from the Part 75 nitrogen oxides and sulfur dioxide monitors will be used to demonstrate compliance with the permit limits.

The excess emissions notification and record keeping requirements from Colorado Regulation 1, Section IV.G have been included in the Operating Permit.

Opacity

Coal-fired electric utility boilers are subject to multiple state and federal opacity standards. Colorado Regulation No. 1 (which is both state and federally enforceable) sets a 20% standard for most periods of operation and a 30% standard for startup, fire building, cleaning of fireboxes, soot blowing, process modification, or adjustment of the control equipment.

Sulfur Dioxide (SO₂)

These units are subject to the Colorado Regulation No. 1. Colorado Regulation No. 6, Part B is not applicable to these sources since the sources had commenced construction prior to 1979.

Colorado Regulation No.1, Section VI.A.3.a.(ii) sets a limit of 1.2 lbs/MMBtu based on a 3-hour rolling average. Colorado Regulation No. 1, Section VI.B.4.(iv) requires good operating practices to be followed during startup, shutdown and upset. The Colorado Regulation No. 1 SO₂ requirements do not allow for exemptions during startup, shutdown or malfunction.

The Title IV Acid Rain program establishes an allowable annual amount of sulfur dioxide emissions. Each allowance is equal to 1 ton per year of SO₂. The number of allowances may be increased or decreased for a unit depending on allowance availability. Allowances are obtained through EPA or the open market and compliance information is submitted (electronically) directly to EPA. The Title IV program establishes how the annual emissions are to be calculated from the continuous monitoring data. The Title IV program does not include any short term limits for sulfur dioxide emissions. Colorado Regulation No. 3, Section V, Part C lists the minimum information to be contained in an Operating Permit. The Item 8 applicable requirement states the Operating Permit shall contain "A permit condition"

prohibiting emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder at 40 CFR Part 72." In addition, pursuant to Colorado Regulation No. 3, Part C, Section V.C.1.b, if a federal requirement is more stringent than an Acid Rain requirement, both requirements shall be incorporated into the permit and shall be federally enforceable. The inclusion of the Title IV permit in the Operating Permit establishes the sulfur dioxide allowances held by the permittee as an emission limit under the Title V Operating Permit. These sources must demonstrate compliance with both the Acid Rain and Colorado Regulation No. 1 requirements.

Nitrogen Oxides (NO_X)

This source is subject to the nitrogen oxides emission requirements of the Title IV Acid Rain program. CSU submitted a nitrogen oxides averaging plan to the EPA. The plan was approved and a Title IV permit issued became effective January 1, 2000.

2. Emission Factors - Emissions from the boilers result from burning natural gas and coal. The primary criteria pollutants of concern are nitrogen oxides (NOx) and sulfur dioxide (SO₂). Continuous emission monitoring systems are provided for monitoring the actual emissions of nitrogen oxides and sulfur dioxide. Standard factors from the AP-42 manual were selected for determining the actual emissions for the other pollutants. The particulate matter emissions are related to the ash content of the coal as reflected by the letter "A" shown in the permit emission factor. The particulate emission factor provides a means to estimate the uncontrolled emissions. Appropriate control efficiencies must also be applied to estimate the actual emissions discharged to the environment.

The facility has the capability to burn coal and natural gas simultaneously. There are no readily available published figures for this scenario for the emissions that must be estimated by calculation. However, based on engineering judgment, the emissions should be representative of each fuel fraction. As such, the emissions for each calculated pollutant under this scenario will be estimated as the sum of emissions from the coal combusted and natural gas combusted.

3. Monitoring Plan - The general operating procedure for this plant is to use natural gas for boiler startup as detailed in the section in this document on natural gas firing. As noted previously the existing Construction Permits for Units 5, 6 and 7 contain no significant limitations. Colorado Regulation No.1 Section IV.b requires fossil fuel fired steam generators greater than 250 million Btu per hour heat input (Units 5, 6 & 7) to be equipped with a continuous emission monitor (CEM) for sulfur dioxide, carbon dioxide or oxygen, and a continuous opacity monitor (COM), or to operate in accordance with a Division approved fuel sampling plan.

Units 5, 6 and 7 are also required by the Title IV Acid Rain Program to be equipped with certified CEMs for NO_x, including diluent gas either CO₂ or O₂, SO₂, stack gas flow rate, CO₂, and a COM. The continuous monitors are required by Title IV to demonstrate that sources are in compliance with the emission allocations or limitations assigned by EPA. Since the monitoring systems are required by Title IV, the Division will require the use of the CEM/COM systems to demonstrate compliance with the opacity, nitrogen oxides and sulfur dioxide requirements. Operation of the CEM/COM systems in accordance with the requirements of 40 CFR Part 75 (Acid Rain Continuous Emission Monitoring Requirements) is sufficient to satisfy the requirements for operating the CEM/COM

systems. Part 75 defines the QA/QC requirements for the COM in §75.21(b) and indicates that the COM shall be operated, maintained and calibrated in accordance with the procedures in 40 CFR Part 51, Appendix M. Appendix M addresses EPA reference methods and no reference methods are listed which appear to address opacity monitors. It appears that this reference is an error, EPA maintains this reference is not an error; however, the intended reference for opacity monitors (reference Method 203) has not been promulgated yet. Therefore, the Division is including the COM calibration requirements from Colorado Regulation No. 1, Section IV.F in the permit for the COM QA/QC requirements. It should be noted that §75.24(e), which addresses COM out of control periods, also references 40 CFR Part 51, Appendix M. This permit addresses alternate requirements for when the COM is out of order (not providing quality assured data). CSU will be required to certify quarterly that they are in compliance with the Acid Rain requirements. Compliance with the particulate standard, when burning coal, is to be demonstrated through annual source testing.

Units 5, 6, and 7 are each equipped with a TECO SO₂ CEM, a TECO NOx CEM, a California Analytical CO₂ CEM, a Dieterich Standard stack gas flow meter and a KVB-Enertec COM. The monitors are currently certified. The monitors are subject to periodic evaluations known as Relative Accuracy Test Audits (RATA) to validate that the monitor is functioning properly.

At this time there is not an acceptable CEM for particulate measurement. There is no information available to establish a meaningful consistent relationship between opacity values and particulate emissions. The particulate monitoring includes the requirement for performance testing. The performance test frequency is based on the results of the most recent test. The testing frequency increases as the test results approach the emission limit. The particulate matter compliance demonstration will also include the use of opacity monitoring for opacity spikes or opacity changes that signal problems with the baghouse. The nitrogen oxides compliance demonstration uses the Title IV monitoring data for demonstration of compliance with the permit limits.

The permittee could use a calculation procedure to estimate actual annual emissions for sulfur dioxide emissions fees. This calculation is dependent on the selection of a value to represent the coal sulfur content for the reporting period. The permittee is required to use the CEM data to determine the actual sulfur dioxide emissions for demonstration of compliance with the Title IV allocation. This creates the potential for two different values being reported for the sulfur dioxide emissions. The difference in the values would be largely dependent on the coal sulfur value selected for the calculation procedure. This problem is avoided by the reporting of the values from the CEM only. The calculation procedure can be used as a check on the reasonableness of the CEM values. Similar reasoning can be extended to requiring the annual emissions of nitrogen oxides to be determined from the continuous emission monitor.

Colorado Regulation No. 1 requires a CEM for sulfur dioxide or a Division approved fuel sampling plan. The sulfur dioxide CEM required by Title IV eliminates the regulatory requirement for a fuel sampling plan. However, a modified coal sampling plan is still needed to monitor for changes in the ash content of the coal that may impact the particulate emissions. The coal sampling program conducted by the permittee for contract performance purposes would be adequate to develop the values to be incorporated in the emission factors. The permit calls for the application of a coal sampling plan that will most likely be an update of the existing plan.

The heat content of the fuel is needed for determining compliance with the heat input based limits. The heat input can be calculated from the carbon dioxide continuous emission monitor and used for determining compliance with the heat input based limits. Fuel sampling values can be used in

calculation procedures to verify the reasonableness of the results determined from the monitored data.

The lead content of the coal poses the possibility of the ambient air lead standard being exceeded. The Operating Permit requires a one time worst-case modeling demonstration to identify the impact of the lead emissions on the ambient air quality. The results of the lead modeling were provided as part of the Title V application. The modeling demonstrated that, even with the selection of conservative values including no lead emission reductions by the fabric filters, the modeled ambient air lead concentrations were magnitudes of order less than the ambient limit. The Division accepts the calculations and modeling adequately demonstrate compliance with the ambient lead standard. CSU has adequately completed the permit lead modeling requirement.

4. Compliance Status - The Division accepts the units were in compliance at the time the Title V application was submitted.

Natural Gas Firing of Boilers
Unit 5 – 514 MMBtu/Hr Riley Boiler
Unit 6 – 850 MMBtu/Hr Babcock & Wilcox Boiler
Unit 7 – 1310 MMBtu/Hr Babcock & Wilcox Boiler

1. Applicable Requirements - Construction Permit C-10,381 for Unit 5 and P-10,402 for Unit 7 have been issued. The information above identifies the steam generator design capacity when firing natural gas. All the units are subject to the requirements of Colorado Regulation No. 1 which sets a particulate emission standard of 0.1 pounds per million Btu for all fuel burning equipment with a heat input design rating of 500 million Btu per hour or more. The calculation below uses the maximum AP-42 emission factor value of 1.9 pounds per million standard cubic feet of gas combusted to demonstrate the combination of the design of the units and the natural gas emission factors prevents the exceedance of the particulate matter standard when burning pipeline quality natural gas.

$$\frac{1.9 \text{ pounds}}{\text{million standard cubic feet}} \times \frac{\text{standard cubic foot}}{986 \text{ Btu}} = \frac{0.00193 \text{ pounds}}{\text{million Btu}} < \frac{0.100 \text{ pounds}}{\text{million Btu}}$$

- **2. Emission Factors** The natural gas combustion emission factors were taken from EPA's March, 1998 edition of the AP-42 reference manual. The facility has the capability to burn natural gas and coal simultaneously. There are no readily available published figures for this scenario. However, based on engineering judgment, the emissions should be representative of each fuel fraction. As such, total emissions under this scenario will be estimated as the sum of emissions from the natural gas and coal fraction.
- **3. Monitoring Plan** The general operating procedure for this plant is to use natural gas for boiler startup. When a boiler must be placed in service from a cold standby, the unit is first heated by burning natural gas, and the flue gas bypasses the baghouse. When the flue gas temperature is greater than the gas dew point, the by-pass is closed and the flue gas flows through the baghouse. The use of natural gas is continued until the turbine is synchronized and on-line. At that time, the coal feed is started, and the natural gas use discontinued after the fire stabilizes. It takes approximately 12 hours to bring the boiler up to the steaming level necessary to operate the turbine.

If a boiler must be taken off-line while burning coal, the coal feed is stopped and the fan is left to operate, blowing the flue gas through the baghouse.

The Division accepts the position that, based on AP-42 emission factors and engineering judgment, the combustion of natural gas in a properly operated facility does not produce enough particulate matter to warrant opacity observations.

4. Compliance Status - The Division accepts that at the time the Title V application was submitted the units were in compliance when burning natural gas.

Title IV Acid Rain Program

Units 5, 6, and 7 are affected units under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78. The sulfur dioxide allowances for this facility are listed under 40 CFR 73.10(b)(2).

The facility is required to continuously measure and record emissions of SO_2 , NO_x , and CO_2 as well as volumetric flow, opacity and diluent gas. The source submitted the continuous emission monitoring (CEM) certification package to EPA on October 31, 1994. The monitoring package has been certified by EPA.

The sulfur dioxide monitor and the flow monitor provide the capability of monitoring the tons per year of sulfur dioxide emissions produced. The yearly production is to be compared to the sulfur allowances held by the source. The monitors can also provide a pounds per hour readout of the emissions. The carbon dioxide monitor allows a calculation of the heat content of the emissions, and can be combined with the sulfur dioxide emissions production to evaluate compliance with the Colorado Regulation No. 1 sulfur dioxide standard. The nitrogen oxide monitor provides the concentration of the nitrogen oxide emissions to be compared against the standard of 0.46 pounds per million Btu of heat input that became applicable in 2000.

P201 Coal

1. Applicable Requirements - Construction Permit 84EP312 was issued August 27, 1986 for "Unloading, conveying, transfer and stockpiling of coal". A copy of the coal handling diagram submitted with the Title V application is included in the Operating Permit. (For the record it is noted that the crusher building contains two crushers.) In viewing the diagram a logical question is why the construction permit is silent in regards to the crusher, the sampling building, and the coal gallery operations. The Master File information was reviewed for this issue.

A January 12, 1984 letter from APCD to CSU states the proposed relocation and modification of the coal unloading, handling and storage facilities to increase the coal processing rate required a permit. The letter referenced an existing Construction Permit, 0760-FD-0035, for a rail car unloading facility. Further, the letter notes that the coal handling and storage activities on the site at the time Permit 0760-FD-0035 was issued were considered to be grandfathered. A document dated August 20, 1984, notes the existence of a crusher house where coal sampling is performed.

A file comment notes that the original permit (0760-FD-0035) was for the rail car loadout only, and the modified permit (84EP312) will specifically cover loading the bunkers, stockpiling and unloading. Reasonable Available Control Technology (RACT) (required when the area was

classified as non-attainment for total particulate matter) for the modifications was considered to be a windbreak at the railroad unloading; chemical application at the unloading point, conveyor transfer points and the stockpiles; and a telescoping stockpile chute. It appears that although the diagram shows a coal sampling building and a coal crusher building, they are the same building. The two grandfathered sources are then the coal crusher building baghouse vent and the coal gallery baghouse vent.

The calculations submitted with the Title V application are a copy of the Division permit calculation sheets for Construction Permit 84EP312. The Title V submittal was annotated to identify various emission points. The annotations incorrectly identify that S201a (crusher), S201b (gallery baghouse vent) and S201g (Load to hopper) are all included in the 0.37 TPY identified as "Load". A review of the Master File information found the "Load" was intended to identify the emissions for conveying the coal from the stockpile to the furnace bunkers. The calculations for Construction Permit 84EP213 did not include emissions from the crusher building or the coal gallery since these two sources were grandfathered, not being modified and not part of the permit. The Master File did include APENs for reporting the emissions from the coal crushing and the coal gallery at the boiler storage bunkers.

Construction Permit 84EP213 included a fugitive dust control plan. The plan was required in order to satisfy the Reasonably Available Control Technology (RACT) requirements of Colorado Regulation No. 1. The plan submitted noted a 5.26 acre stockpile and 3.19 acre overflow pile. The combined storage areas were used in determining the stockpile emissions for the construction permit. The control plan directed the preparation of a specific chemical stabilizer mixture and the application rate for the mixture. CSU found the condition restricted their purchasing options. CSU requested the permit condition be modified to remove the specific mixture and application rates. The modification of the condition is being made directly in this Operating Permit.

The relocation of the coal unloading operation occurred after the October 24, 1974, effective date of 40 CFR Part 60 New Source Performance Standard (NSPS) Subpart Y – "Standards of Performance for Coal Preparation Plants". However, Subpart Y §60.251(h) specifically exempts open storage piles from the provisions. EPA Applicability Determination NR 90 clarified that Subpart Y does not apply to the conveyor systems moving the coal from the train to the coal stockpile. As a result of the exemption this portion of the coal handling system is not subject to the Subpart Y provisions.

CSU was making modifications to the coal handling system while this Title V permit was being prepared. New coal crushers were being installed and the system for moving the coal to and from the crushers was modified. A temporary coal crusher and associated conveyors is needed to process the coal while the new system is being constructed. Construction permits were obtained for the both the temporary and new systems and are included in this Title V permit. In addition, CSU obtained a construction permit for the coal handling augmentation work performed by front-end loader operations on the coal stock pile. The construction changes make the new coal crushers and associated conveyor systems subject to NSPS Subpart Y. The coal bunker gallery and the coal bunker charging remain grandfathered from the regulatory requirement for a construction permit.

2. Emission Factors - The particulate emission factors were taken from the calculation sheets for the Construction Permit 84EP312. The permit calculations did not include PM_{10} emission factors because PM_{10} emissions were not recognized at the time the construction permit was prepared. A review of the reference material available indicates coal handling PM_{10} emissions are approximately

50% of the total particulate emissions. Further, the emissions from a baghouse are considered to be all PM₁₀ emissions. The tables attached to the end of this document display how the coal handling particulate emissions were calculated for the construction permit.

A wet suppression system is used to apply a chemical dust control agent to the coal at the rail car unloading hopper, at conveyor transfer points, and on the stockpiled material. Baghouse systems are provided on the crusher building and the for the boiler bunker distribution system. Additional control measures include the masonry wall wind breaks at the rail unloading hopper, enclosure of the conveyors, a telescoping chute with tilt switches, dust curtains at the entry points, and compaction of the stockpile material. All of these control efforts were given an emissions removal efficiency at the time of the original calculations. These removal efficiencies have been recognized in the emission factors shown in the summary tables in the Operating Permit.

3. Monitoring Plan - The amount of coal delivered is monitored by belt scales that continuously weigh the coal as it is moved from the rail car unloading hoppers to the stockpile, and from the stockpile to the boiler bunkers. The emissions are calculated from the monitoring records on the amount of coal being processed. Daily inspections will be made for visible emissions from the various sources. The presence of visible emissions will require investigation of the problem and Method 9 opacity observations as necessary.

Compliance with the annual particulate matter emission limit will be demonstrated by calculation using the amount of coal processed and the permit emission factors. Records of the amount of chemicals used to control fugitive emissions will also be maintained.

4. Compliance Status - The Division accepts the units were in compliance at the time the Title V application was submitted.

Temporary Coal Processing and Handling System

Construction Permit 02EP0253 was issued to CSU for a temporary coal processing and handling system. The temporary system will provide the conveyor system and a coal crusher needed to bypass the existing coal crushing operation while the crushing operation is upgraded. If this Construction Permit is cancelled prior to this Operating Permit being issued this section of this document and the relevant sections of the Operating Permit will be removed.

- **1. Applicable Requirements** The applicable requirements were established by Construction Permit 02EP0253. The Construction Permit expires April 20, 2003, or upon startup of the permanent coal preparation and handling system. It should be noted that the two opacity limits are slightly different. Colorado Regulation No. 1 states the opacity is not to exceed 20%. NSPS Subpart Y states the opacity shall not be 20% or greater. A 20% opacity reading demonstrates compliance for Regulation No. 1, but is non-compliance for the NSPS.
- **2. Emission Factors** The emission factors for the transfer point(s) was obtained from equation #1 of AP-42 Section 13.2.4. An average wind speed of 5.29 miles per hour and average coal moisture content of 15.57% were used in the equation. A control efficiency of 85% was applied for spray bar use at the transfer point.

The coal crusher emission factor was obtained from EPA FIRE 6.23 database. A control efficiency of 99% was applied for the dust collector on the crusher building.

- **3. Monitoring Plan -** The presence of visible emissions identifies the need to investigate and correct a problem. Method 9 opacity observations are required if the problem persists after the correction(s) have been made
- **4. Compliance Status** The Division accepts the system was in compliance at the time the Title V application was submitted.

Coal Crushing

While the Title V permit was being prepared CSU modified the coal crusher to provided two parallel crushers. The reclaim conveyor and the feed conveyor to the crusher were also modified as part of this change.

- **1. Applicable Requirements** The applicable requirements were established by Construction Permit 02EP0336. The reclaim conveyor, the feed conveyor and the crushers are subject to the provisions of Colorado Regulation No. 1, Section II.A.1, Colorado Regulation No. 6, Part A and 40 CFR Part 60 New Source Performance Standard (NSPS) Subpart A "General Provisions" and Subpart Y "Standards of Performance for Coal Preparation Plants". It should be noted that two slightly different opacity limits are created. Colorado Regulation No. 1 states the opacity is not to exceed 20%. NSPS Subpart Y states the opacity shall not be 20% or greater. A 20% opacity reading would be in compliance with Regulation No. 1, but not in compliance with the NSPS.
- **2. Emission Factors** The emission factors for the transfer point(s) was obtained from equation #1 of AP-42 Section 13.2.4. An average wind speed of 5.29 miles per hour and average coal moisture content of 15.57% were used in the equation. A control efficiency of 85% was applied for spray bar use at the transfer point.

The coal crusher emission factor was obtained from EPA FIRE 6.23 database. A control efficiency of 99% was applied for the dust collector on the crusher building.

- **3. Monitoring Plan** The presence of visible emissions identifies the need to investigate and correct a problem. Method 9 opacity observations are required if the problem persists after the correction(s) have been made
- **4. Compliance Status** The Division accepts the system was in compliance at the time the Title V permit was prepared.

Coal Handling Augmentation

While the Title V permit was being prepared CSU was issued Construction Permit 01EP0889 to address the emissions produced by the activities of front-end loaders moving coal and the use of an elevating conveyor. These activities were discontinued and the Construction Permit cancelled before the Title V permit was issued.

P202 Flyash

Process Description

A diagram of the flyash processing system is included in Appendix A of the Operating Permit. Some additional explanation is necessary for a proper understanding of the overall process. A dedicated vacuum system collects the flyash through an inlet feeder on the air pollution control equipment of each steam generating unit. The collected flyash is pneumatically conveyed through a cyclone that uses inertial force to separate and collect the flyash from the air. The air still retains some flyash and passes through a fabric filter before reaching the vacuum blower. The air from the vacuum blower exhausts through a silencer to the atmosphere. The flyash collected in the separator/collector is moved by a pressure blower to the flyash storage silo. The displaced air in the silo is discharged to atmosphere through a fabric filter. The storage silo is emptied by either two dry unloading chutes or two wet unloaders. The dry unloading chutes have telescoping spouts that form a closed system. The air displaced from the truck is piped back into the silo. The wet unloaders utilize pug mills for mixing water with the flyash before discharge into the trucks. There are four (4) vacuum blower systems for the three (3) steam generators. This makes a backup unit available at all times.

- 1. Applicable Requirements The applicable requirements were established by Construction Permit 92EP590. Condition 5 of the Construction Permit requires CSU to follow the most current version of the Division approved operating and maintenance plan. This requirement was modified directly in the Operating Permit to remove the requirement for Division approval of the plan.
- **2. Emission Factors** For inspection and monitoring purposes, it is desirable to estimate the emissions for each blower system, the storage silo vent and the unloading area of the silo. Engineering judgment and experience were used to apportion the total estimated emissions to the various vent points. No emissions were assigned to the standby blower collector/separator unit since it only operates when there is need to take one of the operating units out of service.

Emission factors for flyash handling are not readily available. The factors selected by the permittee represent a reasonable approximation of the expected emissions. The estimated actual annual emissions are quite low because of the presence of the air pollution control equipment with a high removal efficiency. The tables shown at the end of this document are provided to document how the flyash emissions were calculated. The limited literature available indicates that PM_{10} emissions are approximately 50% of the total particulate matter. The emissions from an air pollution control device are expected to be entirely PM_{10} emissions.

There is a very small calculation flaw for this process. The amount of flyash produced is measured by the weight of material discharged to the hauling trucks. This measurement is not the actual amount of flyash produced because it does not include the flyash lost at the various emissions points. The flyash emissions should actually be based on a slightly larger number that would account for the losses. However, the control practices limit the amount of material emitted to the atmosphere to a small fraction of the total material processed. This error is not considered significant and compensated for by the conservative estimates used for the air pollution control device removal efficiencies.

3. Monitoring Plan - The quantity of flyash generated is determined by recording the weight of each truck load of flyash removed from the silo. The most current version of the operating and monitoring plan is to be followed and kept available for review by the Division upon request.

An opacity observation of less than 20% does not necessarily demonstrate compliance of the emissions with the particulate limits. An opacity observation of 20% or greater may be considered evidence of the potential exceedance of the particulate emission limitation. Weekly observations will be made to identify persistent visible emissions that could indicate an air pollution control device malfunction, and trigger the requirement for a Method 9 observation. The problem(s) creating the need for Method 9 observations and the correction of the problem(s) shall be documented.

4. Compliance Status - The Division accepts the units were in compliance at the time the Title V application was submitted.

Cooling Towers P206 for Unit B005 P208 for Unit B006 P211 for Unit B007

- **1. Applicable Requirements** Units 5, 6, and 7 each have their own cooling tower. Since the towers are grandfathered from the requirement to have construction permits the applicable requirement for the cooling towers is to report their estimated actual annual emissions.
- **2. Emission Factors** Particulate matter and volatile organic compounds are the criteria pollutant emissions expected from the cooling tower. The estimated volatile organic compound emissions are calculated from the amount of water circulated through the cooling tower and a chloroform emission factor. The generic chloroform emission factor for cooling tower chlorination and operation was obtained from a letter from Mr. Wayne C. Micheletti to Mr. Ed Lasnik of the Tri-State Generation & Transmission Association. The Division accepted the use of the emission factor after review of the letter.

AP-42 provides a low quality emission factor for estimating the particulate matter emissions. CSU requested the use of an equation based on an Air and Waste Management Association abstract detailing calculations of particulate matter emissions from cooling towers (Abstract No. 216 Session No. AM-1b "Calculating Realistic PM₁₀ Emission from Cooling Towers" by Reisman and Frisebie) The abstract points out that at high concentrations of total dissolved solids in the water circulated in the cooling tower, the particulates formed by the mineral matter left after the evaporation of the moisture from the drifting water droplets favors the formation of particulate matter larger than PM₁₀. The particulate matter is estimated from the amount of water circulated through the cooling tower, the total dissolved solids in the water, a conservative estimate of the drift loss from the tower and a factor accounting for the amount drift lost that remains in the air. After reviewing the information submitted, the Division accepted the use of the estimation equation included in the permit.

3. Monitoring Plan - The amount of water circulated, the amount of chlorine applied, and the mineral concentration have to be determined for making the emissions estimate calculations.

4. Compliance Status - The Division accepts the units were in compliance at the time the Title V application was submitted.

IV. Alternate Operating Scenarios

The Title V application includes two alternate operating scenarios. One scenario is for the disposal of spent boiler tube cleaning materials in a boiler. The other scenario is for the salvage of coal residual from the solar evaporation pond.

Spent Boiler Tube Cleaning Materials - Circulation of water through the boiler tubes results in an accumulation of mineral deposits over time. The mineral deposition decreases the efficiency of the heat transfer from the boiler tube to the circulating water. Periodically, the tubes are cleaned to recover the heat transfer efficiency. Operating experience for this utility has identified the need to clean the tubes approximately once every 10 years. The cleaning is accomplished by circulating cleaning solutions, generally strong acid and detergent mixtures, through the tubing. Commonly, the accumulated spent materials are slowly injected into an operating boiler for disposal. This has been an on-going practice for other boilers operated by the utility and has not been cited by the Division as a compliance issue. The quantity of the materials requiring disposal is reported to be limited. A laboratory chemist establishes a material feed rate that will accomplish the complete combustion of the materials. The combination of the limited quantities, the injection rate and the combustion temperatures of the boiler are expected to result in proper disposal of the materials. The Division, however, needs to be aware of when and how much material is being processed. An opacity observation is required to provide a direct indicator of proper operation during the material disposal. The operating permit limitations may have to be adjusted if the type of materials is different than expected or the quantity of materials is greater than expected.

Coal Residue Salvage - Periodically coal residue from the solar evaporation ponds is removed and returned to the coal pile for burning. This practice has no affect on emissions from the boilers. No reporting or notification is required for this operation.

V. Permit Shield

In the Title V application the permittee requested the Division either waive, or provide the permit shield protection, from the Colorado Regulation No. 7 §VI.B.2.b requirement for a solar reflective coating on the storage tank for No. 6 fuel oil. The requirement appears to be the result of an administrative oversight during a regulatory change. While the Title V permit was being prepared the permittee stopped using No. 6 fuel oil. Since No. 6 fuel oil is no longer stored, the need for the permit shield is now moot.

The permit shield was requested from NSPS Subpart A and Subpart D and Colorado Regulation No. 6 Part A for Units 5, 6 and 7. The permit shield was granted on the basis that the units existed prior to the August 17, 1971 applicability date for NSPS.

The permit shield was requested from Colorado Regulation No. 6 Part B, Section II – Standards of Performance for New Fuel-Burning Equipment for Units 5, 6 and 7. The permit shield was granted on the basis that the units existed prior to the January 30, 1979, applicability date of Regulation No. 6.

The permit shield was requested from Colorado Regulation No. 1 Section III.C.1.b – Particulate Matter from Manufacturing Processes for the cooling towers. The permit shield was granted on the basis that the Standard Industrial Classification code for the cooling towers does not fit the code for manufacturing.

The permit shield was requested from Colorado Regulation No. 6, Part B, Section III – Standards of Performance for New Manufacturing Processes for the cooling towers, the coal handling and the flyash silo baghouse vent. The permit shield was granted on the basis that the Standard Industrial Classification code for these sources does not fit the code for manufacturing.

The permit shield was requested from Colorado Regulation No. 6, Part A, NSPS Subpart Y – Standards of Performance for Coal Preparation Plants for the coal gallery baghouse vent. The permit shield was granted on the basis that the source existed prior to the October 24, 1974, NSPS applicability date.

The permit shield was requested from the Compliance Assurance Monitoring (CAM) provisions of 40 CFR Part 64. The permit shield was granted on the basis that the Operating Permit application was deemed complete prior to April 20, 1998, and the CAM provisions do not become applicable until the Operating Permit is renewed.

The permit shield was requested from the Prevention of Significant Deterioration (PSD) provisions of 40 CFR Section 52.21 and Colorado Regulation No. 3, Part B, Section IV.D.3. The permit shield was granted on the basis that the sources existed as of the August 7, 1977 applicability date of 40 CFR Section 52.21

The shield does not protect the source from any violations that occurred prior to or at the time of the issuance of this Operating Permit. In addition, the shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

VI. Accidental Release Program – 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provision must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plan (RMP) as specified in the Rule.

At the time the initial Title V application was submitted Drake stored sulfur dioxide gas used for the Unit 5 precipitator gas conditioner. The storage of the sulfur dioxide made the plant subject to the 112(r) provisions as stated in the application. The control system has been modified and sulfur dioxide gas is no longer used or stored. The Title V application has been modified to identify the plant is not subject to the provisions of the Accidental Release Plan of Section 112(r)(7) of the Clean Air Act.

VII. Hazardous Air Pollutants

At the time the Title V application was submitted, the reporting of estimated actual hazardous air pollutants (HAPs) emissions from combustion at utility steam boilers used for electrical power

generation had been deferred until the findings of an EPA scientific study were released, or September 30, 1996, whichever came earliest. In an effort to provide an estimate of the potential-to-emit for the combustion HAPs, the Title V application used emission factors available from AP-42 for calculation of the best available approximation of the emissions. The permittee has reported the estimated HAPs to the Division in accordance with the September 30, 1996, deadline.

VIII. Fugitive Particulate Emissions

The provisions of Colorado Regulation No. 1 §III.D require existing sources to employ control measures to minimize fugitive particulate emissions. In general, the 20% opacity and no off-property transport are guidelines, not enforceable applicable requirements. The Division can require the submission of a fugitive particulate control plan if there is an exceedance of the opacity guideline or problems created by off-property transport. Enforcement action against existing fugitive particulate sources can be taken only if a permittee continues to operate after a control plan, or a portion of a control plan, has been disapproved, or fails to comply with the provisions of an approved control plan.

IX. Miscellaneous

Between the time the Title V application was submitted and the draft operating permit was prepared, the permittee had removed the No. 6 residual oil storage tank and associated plumbing. The burners on the boilers were changed to provide low nitrogen oxide emissions to maintain compliance with the lower nitrogen oxides limit accepted for the Title IV program.

The Division data base identified lime, soda ash and magnesium oxide chemical handling systems to be present at the facility. The application was silent regarding these systems. The permittee confirmed that this equipment has been dismantled and removed from operation.

A number of the forms were not provided with the application. The information that would have been provided by the missing forms was available on other forms, or elsewhere in the application. The judgment was made that no beneficial purpose would result from requiring the submission of the missing forms.

From time to time published emission factors are changed based on new or improved data. A logical concern is what happens if the use of the new emission factor in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors or emission factor equations included in the permit are considered to be fixed until changed by the permit. Obvious factors dependent of the fuel sulfur content or heat content can not be fixed and will vary with the test results. The formula for determining the emission factors is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors, and to notify the Division in writing of impacts on the permit requirements when there is a change in factors. Upon notification, the Division will work with the permittee to address the situation.